**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning and Evaluation of Integrated Distributed Energy Resources.	Rulemaking 14-10-003 (Filed October 2, 2014)

COMMENTS OF SOLARCITY CORPORATION ON THE COMPETITIVE SOLICITATION FRAMEWORK WORKING GROUP FINAL REPORT

KEYES, FOX & WIEDMAN LLP
Jason B. Keyes
436 14th Street, Suite 1305
Oakland, CA 94612
Tele: (510) 314-8203
Email: jkeyes@kfwlaw.com

Counsel for SolarCity Corporation

August 22, 2016

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Pursuant to the *Joint Assigned Commissioner and Administrative Law Judge Ruling and Amended Scoping Memo*, issued on February 26, 2016, SolarCity Corporation (SolarCity) respectfully submits these opening comments on the Competitive Solicitation Framework Working Group Final Report, submitted on August 1, 2016.

I. DESCRIPTION OF SOLARCITY

SolarCity is California's leading full service solar power provider for homeowners and businesses, a single source for engineering, design, financing, installation, monitoring, and support. The company provides cost effective financing that enables customers to eliminate the high upfront costs of deploying solar. SolarCity has more than 5,000 California employees based at more than 40 facilities around the state and has provided clean energy services to more than 285,000 customers nationwide as of June 30, 2016.

II. INTRODUCTION

SolarCity has been an active participant in the Competitive Solicitation Framework Working Group (CSFWG) since its inception. The CSFWG was charged with developing a consensus-based set of recommendations to the Commission to inform the approach the utilities take to procure distributed energy resource (DER) solutions to address grid needs emerging out of a process that is still under development in the closely related Distribution Resources Plans (DRP) proceeding, Rulemaking (R.)14-08-013. More specifically, as the name suggests, the

CSFWG was focused on the solicitation process that will serve as one of the means by which the utilities source DERs. Numerous parties have provided comments expressing concerns with relying on solicitations as the primary means of procuring DER solutions, SolarCity among them. We will not reiterate those comments here, beyond noting that our engagement in the efforts of the CSFWG should not be construed as a change in position with regard the important role we see other sourcing mechanisms playing as the Commission looks to leverage DERs to address grid needs.

SolarCity believes the working group process and resulting Final Report provide a useful point of departure to the extent they have provided a comprehensive sense for the scope of issues that need to be addressed as part of any solicitation process. While consensus eluded the group across many issues, the identification of those issues is an accomplishment in its own right. Additionally, we are particularly pleased with the consensus related to the nature of the services to be solicited, where there appears to be consensus on the notion of soliciting for needs rather than for specific technologies. This approach will ensure that any solicitation does not prejudge the types of DERs that may by submitted and thus will fully tap into the creativity of the market and support the widest array of potential solutions. SolarCity believes this technology-agnostic approach is absolutely essential to achieving the goals of the DRP and IDER proceeding.

In the comments below, SolarCity identifies a number of specific concerns with the Final Report and/or articulates our position on certain issues where there was not consensus. However, despite these concerns and/or lack of consensus, we also want to encourage the Commission to move forward with allowing the utilities to pursue solicitations in the service of the DRP and IDER proceedings. SolarCity believes that there is tremendous value to be gained via "learning by doing" and hopes that consensus across all of the issues identified is not being treated as a gating issue in the immediate term. We note that in the context of the DRP the utilities have proposed a number of demonstration projects that will rely on utility solicitations. These will provide real world experience with the solicitation process that can further inform the perspectives of stakeholders as well as the Commission. SolarCity suggests it may be useful to reconvene the CSFWG subsequent to the issuance and completion of these solicitations to discuss how that experience can be used to further refine the recommendations of the CSFWG.

III. DISCUSSION

a. Technology Neutrality Should Be Maintained Throughout the Solicitation Process.

While there was general agreement that the utilities should solicit DERs solutions that can address specific needs, rather than soliciting specific DER technologies or portfolios, SolarCity is concerned that there are certain aspects of the Final Report that continue to reflect a technology specific approach. For example, the CSFWG Final Report discusses the need to establish project milestones that developers would need to meet, stating, "These pre-commercial milestones will involve the DER provider submitting scheduled progress reports on the status of the construction of DERs and associated equipment that are needed to provide the contracted distribution services."[1] SolarCity understands that the utilities will need to assess the extent to which a given project developer is making progress in deploying the solution that they are under contract to provide and that some level of periodic assessment regarding where deployments stand will be an essential part of that. However, we also believe it will be important that developers be provided flexibility in terms of the specific technologies ultimately deployed to address a given need rather than being locked into a given portfolio.

The best way to achieve this flexibility would be to eschew assessing progress based on technology deployment altogether and instead establish a framework whereby progress is assessed on the basis of the percent of the overall performance target a developer has achieved by specified dates. For example, if the solution provider is contractually required to deliver the ability to reduce load on a circuit by amount X by date Y, one could set interim performance milestones, i.e. dates by when the developer would need to be able to show that the portfolio of resources deployed can deliver some percentage of the overall targeted amount of load drop. This approach would be completely indifferent to the manner in which developers actually achieve the target, providing maximum flexibility to developers while still holding them accountable to deliver under their contracts.

To the degree the utilities feel they need to measure widgets deployed as opposed to performance achieved, at a minimum the process needs to acknowledge that different DERs can serve as substitutes for one another while delivering the same level of overall performance. For example, consider a portfolio of resources consisting of behind the meter batteries and load controls in the form of electric water heaters and programmable thermostats intended to help

[1] CSFWG Final Report, p. 14.

integrate solar energy in an area with high solar penetration. Provided the portfolio is able meet the overall performance needs, in terms of integrating the solar resource, we believe the utility should be indifferent to the specific mix of technologies that are actually deployed to achieve those results.

This flexibility will be particularly important in the context of behind the meter solutions where the actual portfolio share of different technologies will depend on customer uptake. Such flexibility could be included as an express part of the agreement up front, whereby the solution provider and the utility could agree to allow some technologies or approaches to be swapped out as needed, which would allow for a different portfolio than what was initially anticipated to still be deemed as in compliance with any deployment milestones. Regardless of how this flexibility is reflected in the overall process, it is an important element that SolarCity believes should be explicitly included.

b. Solution Providers Should Have an Opportunity to Cure Any Deficiency.

The CSFWG Final Report would benefit from some additional discussion regarding the opportunity to cure any deficiency that is discovered through the envisioned performance and measurement process. As described in the Final Report, there does not appear to be an opportunity for a developer to address any deficiency through the deployment of additional DERs. For example, the figure provided on page 14 appears to pursue a wires alternative back-stop shortly after the "DER service event", without any express indication that a developer would have an opportunity to cure. SolarCity appreciates that in the case of many of the services to be provided by DERs, there will need to be sufficient lead time to pursue a more conventional wires solution should the non-wires solution fail to perform as anticipated. However, in building out the schedule for this process, SolarCity contends there should be an explicit opportunity to cure any identified deficiency before a utility begins to deploy the wires solution back-stop.

c. The Concept of Additionality Should Encompass Using Existing DERs to Provide Additional Services.

There was extensive discussion in the working group regarding how to ensure that the resources being solicited can be deemed additional or incremental to what would otherwise occur absent the solicitation. Given the deployment of DERs that can be reasonably anticipated to occur, some have expressed the concern that any solicitation could run the risk of forcing the utilities and by extension ratepayers to pay for the deployment of DER assets that would have happened anyway, thus increasing costs to ratepayers. As an initial matter, SolarCity is concerned that this issue could easily become the proverbial "tail wagging the dog" and cautions the Commission about spending too much time attempting to address this issue. To the extent there is some level of organic growth in the deployment of DERs that address a given need, those projections should be included as part of the need determination that sets the stage for any specific solicitation. At that point any solicitation should be deemed incremental to what would otherwise occur and any DER solutions that are submitted as part of a solicitation should similarly be deemed incremental. We also note that the issue of how to forecast DER growth has been teed up for discussion in the DRP proceeding, specifically in Track 3.[2]

Irrespective of where the Commission lands on the issue of how to assess whether a given set of DER solutions offered in response to a solicitation is additional to the underlying growth forecast, SolarCity believes it is important to recognize the distinction between the *types of assets* being deployed and the *services being provided* by those assets. For example, while the utilities may reasonably forecast that a certain number of rooftop photovoltaic (PV) systems will be deployed in a given locality and that those systems will generate a certain amount of energy during certain time frames, this should not preclude a solution provider from offering those systems as part of a solution in response to a solicitation to the degree the services being offered arise from system use that is different than system use under business as usual.

Continuing with the solar PV example, the utilization of smart inverters to provide certain services that cannot be assumed to be provided under business as usual operation should be deemed as incremental or additional even if the assets themselves were included as part of the forecast DER growth scenario. For these reasons, although consensus was not achieved through the working group process, SolarCity strongly supports the first principle identified on page 18 of the CSFWG Final Report, which states, "An incremental DER will provide an attribute (aka service) that was not included in the planning assumptions used by the distribution planning engineer when determining if a traditional infrastructure investment is needed to ensure continued safe and reliable operation of the distribution grid."

[2] *Assigned Commissioner's Ruling on Track 3 Issues*, R.14-08-013, August 9, 2016, pg. 4.

d. Issues Regarding the Investment Needs Being Driven by Greater Reliance on DERs Should Be Addressed in the DRP Proceeding.

The CSFWG Final Report states on p. 15 that, "Operationally, the utility may need to build new capabilities in forecasting, monitoring, and grid resource management to enable higher penetration of DERs and provide grid services. Forecasting compresses to near real-time to support coordinated transmission and distribution grid planning, control system algorithms, and decision implementation. Advanced monitoring for real-time situational awareness, power quality awareness, distribution load flow analysis and accurate monitoring requires enormous levels of data collection from individual circuits and distributed energy resources at more frequent intervals than before. New predictive capabilities provide the utility with data-driven insights to understand the local impact of distributed energy resources."

SolarCity believes this language potentially prejudges the determination to be made in the DRP proceeding and thus encroaches on the scope of that proceeding. While there may very well be incremental investments beyond the business as usual that the utilities will need to make to support increased reliance on DER solutions, SolarCity is particularly concerned about costs being attributed to DERs exclusively, particularly to the degree many of these investments would or should be made regardless of the increased role of DERs. Notably, the issue of what investments are necessary to support the DRP vision was included as a "Track 3" issue in the DRP in the Scoping Ruling issued on August 9, 2016 under "Sub-track 2".[3]

e. Reactive Power Support and Conservation Voltage Reduction Should Be Recognized as Tangible Services that DERs can Provide.

The CSFWG Final Report indicates that there were a number of additional services that DER providers may be able to offer that were discussed as part of the working group process. However, the Final Report notes that no consensus was reached regarding the ability or future opportunity to procure reactive power support or conservation voltage reduction benefits from DER providers. SolarCity believes these are real benefits that need to be acknowledged in some way, at a minimum incorporated into any valuation of DER resources. SolarCity has done extensive analysis regarding the role that DERs can play in reducing conservation voltage and the value this could provide when properly incorporated into utility conservation voltage

[3] *Id.*

reduction schemes. For reference we append to these comments as Attachment 1 a white paper developed by SolarCity's Grid Engineering Solutions Team that describes the positive impacts that DERs can have on conservation voltage reduction as well as a methodology that quantifies this benefit. To the degree benefits like this can be quantified, we believe the Commission and the utilities should seek to recognize these benefits and provide incentives that would motivate the developer community to bring these solutions forward.

f. Real Option Value of DERs Should Be Recognized in the Valuation Framework.

Conventional wires solutions are characterized by a high degree of "lumpiness" whereby the utilities make large capacity additions recognizing that for many projects a significant share of costs incurred in installing the equipment are the same regardless of the amount of capacity being deployed. Thus, from a per unit cost standpoint, it is cheaper to install a larger transformer than a smaller transformer or a larger capacitor bank than a smaller capacitor bank. However, to the degree utility investment decisions are based on relatively long-term forecasts of load growth, this approach also creates non-trivial risk of stranded assets should the load on which a given investment was predicated fail to materialize. In contrast, if a utility is relying on DER solutions, the scale of deployment can be tailored to the level of the need that is actually occurring, limiting the risk of excess capacity. Put another way, reliance on DERs allows for greater optionality should circumstances change as compared to more conventional alternatives. Additionally, by scaling deployment based on realized need as opposed to forecast need, the net present value of the investment associated with DER-based solutions may actually be lower than a conventional investment, even absent the option value DERs afford, owing to the effects of discounting.[4] Neither of these benefits is expressly recognized in the CSFWG Final Report. While there may not be consensus on the role of these values in an evaluation framework, SolarCity believes it is important to flag these items for additional discussion and consideration.

[4] For a more detailed discussion of this, see the SolarCity White Paper "A Pathway to the Distributed Grid", pp. 23-24, available at http://www.solarcity.com/company/distributed-energy-resources.

g. The Characterization of a Number of Valuation Components as Qualitative Should Be Deemed as Interim Pending the Development of a Quantification Methodology.

The CSFWG Final Report includes a table in Appendix 3: Evaluation Methodology Details that provides an overview of the various "valuation components" that would or should be included in any valuation of DERs submitted in response to a solicitation opportunity. SolarCity believes this list does an excellent job of identifying a near comprehensive set of benefit and cost categories that should be incorporated into a valuation. However, we do wish to note that the "qualitative" categorization of a number of items is an interim characterization pending the development of a methodology to quantify these components. In discussions on these items, SolarCity understands there was general agreement that a number of components identified as qualitative do lend themselves to quantification, but there was not consensus on a methodology to do so. The valuation components for which this is relevant include both Conservation Voltage Reduction and Reactive Power Support Services, as discussed above, which provide real and quantifiable value to the utilities and by extension ratepayers. Similarly, Frequency Services, Power Quality Services and Equipment Life Extension Services are all examples of things the utilities achieve or address through actual physical investments in infrastructure or via the procurement of services in the market, and therefore lend themselves to quantification via an avoided cost methodology. We encourage the Commission to actively pursue efforts to develop a quantification methodology for each of these valuation components.

h. The Commission Should Endeavor to Expand the Type of Information and Data Provided to Market Participants.

In the Final Report's discussion of the Distribution Planning Advisory Group (DPAG), it notes the utilities' concerns with allowing market participants (MPs) to be involved in the activities of the DPAG, stating, "The IOUs raised market manipulation and confidentiality concerns related to MP participation."[5] The Final Report also correctly notes that other parties have "expressed interest in MP participation in the DPAG related to some or all of the DPAG activities…"[6] As an initial matter it is not entirely clear if this issue is appropriately within the scope of the IDER proceeding as opposed to something that would be better addressed in the

[5] CSFWG Final Report, p. 34.
[6] *Id.*

DRP proceeding. The recent Assigned Commissioner Ruling issued in the DRP proceeding indicates that sub-track 3 will "consider the processes for integrating DRPs into utility distribution planning and investment, including how the identification of deferral opportunities or other high value locations for DER deployment will lead to solicitations for DER services (or other market opportunities)…"[7] How this inquiry relates to the discussions in the IDER proceeding should be further clarified.

This ambiguity notwithstanding, SolarCity wishes to note for the record that to the degree the Commission envisions truly leveraging DER solutions, it will be critical to establish a means by which market participants, many of whom have deep technical knowledge, can access a much broader set of data than has heretofore been made available. In the DRP proceeding, SolarCity submitted comments regarding the types of data that we feel should be provided to market participants and the rationale for doing so. We incorporate those comments here by reference.[8] Further, in the DRP proceeding, SolarCity is submitting comments today (August 22, 2016) in response to the recently issued *Assigned Commissioner's Ruling on Track 3 Issues*, in which we call for the inclusion of data access within the proposed Track 3 as well as the establishment of a data access working group.

We also respectfully push back on the utility concerns regarding the need to hold as confidential much of this information. For example, the utilities have indicated that they believe the cost of the traditional wires solutions to address a given grid need should not be provided to market participants because doing so will impact these entities' bid strategy, presumably resulting in these entities increasing their offer price to something just below the cost of the traditional solution. This concern implies that the market for the services sought is non-competitive, or that collusion would occur, which are both unsubstantiated and highly contestable assumptions. In a competitive market with more than one participant, solution providers would bid in at marginal cost, regardless of the cost of the solution being deferred or replaced, or risk not being selected.

Additionally, it is important to note that in the context of the DRP, any cost risk to ratepayers is strictly bounded on the high end by the cost of the traditional wires solution. Under

[7] *Assigned Commissioner's Ruling on Track 3 Issues*, R.14-08-013, August 9, 2016, p. 5.
[8] *Response of SolarCity Corporation to the Administrative Law Judge's Ruling Instructing the Utilities and Non-Utility Parties to Answer Data Request*, R.14-08-013, May 13, 2016, available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M162/K005/162005239.PDF.

the worst case scenario, if DER providers cannot offer a lower cost/better fit alternative to the traditional solution, ratepayers would simply end up paying for the traditional solution, in other words, the current status quo. Lastly, SolarCity notes that the ability to develop a viable bid to address a grid need is not without cost. By providing the cost of the traditional wires solution upfront in the solicitation, solution providers would have the opportunity to determine whether they should invest in the resources necessary to develop a bid that would potentially be viable against the traditional wires solution.

Similarly, the utilities have indicated that they should not be required to make their bid evaluation methodology available to market participants, again on the grounds that gaming could occur that will be to the detriment of ratepayers. However, the utilities have not presented any specific examples or scenarios where such gaming might be anticipated to occur.

On the other side of this debate, there are good reasons for why this information should be provided to market participants. First, providing this information will help ensure that solution providers are developing and tailoring bids that maximize the level of benefits being provided to the utilities and ratepayers. Additionally, we believe the provision of this information will provide an additional check on the utilities. While the utilities have expressed concerns regarding the opportunity for developers to game the system, the veil of secrecy under which the utilities currently develop their investment plans and evaluate bids creates its own set of risks to the degree the utilities continue to have a strategic business interest in the outcomes of their procurement activities. Increasingly third party solution providers have deep technical knowledge that can help evaluate and assess the technical underpinnings of the utilities' investment needs.

III. CONCLUSION

SolarCity appreciates the work by all stakeholders as well as Commission staff over the past several months on these issues, as well as the opportunity to provide these comments on the CSFWG Final Report.

Respectfully submitted at San Francisco, California on August 22, 2016,

BY: /s/

KEYES, FOX & WIEDMAN LLP
Jason B. Keyes
436 14th Street, Suite 1305
Oakland, CA 94612
Tele: (510) 314-8203
Email: jkeyes@kfwlaw.com

Counsel for SolarCity Corporation

ATTACHMENT 1

Energy Efficiency Enabled by Distributed Solar PV via Conservation Voltage Reduction

A methodology to calculate the benefits of distributed PV with smart inverters in providing conservation voltage reduction

SolarCity

Grid Engineering

Technical Brief

Key Takeaways

Takeaway 1

Conservation voltage reduction (CVR) is a common utility strategy to improve grid operations by more efficiently managing voltage profiles at the distribution level. Distributed solar photovoltaics (PV) with smart inverters can improve the efficacy of CVR schemes by lowering overall system consumption, reducing peak demand, and decreasing greenhouse gas emissions.

Takeaway 2

Distributed PV with smart inverters can increase the benefits of utilities' CVR schemes by over 10%. These improvements reduce customer energy consumption and peak demand by 0.4% annually, resulting in benefits of 1.0¢ to 2.9¢ for every kilowatt-hour (kWh) of PV generation. A detailed methodology and accompanying calculator are provided to facilitate replication of the benefits quantified herein.

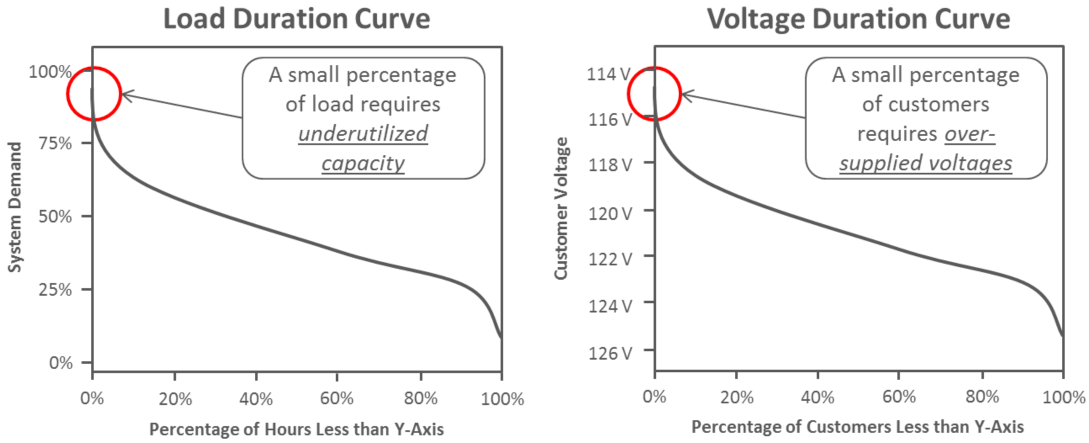
Takeaway 3

Smart inverters are readily available today, and will soon be deployed by default with all distributed PV systems. Capturing smart inverter benefits via CVR schemes is straightforward and does not require incremental infrastructure investments. Distributed PV with smart inverters can deliver CVR benefits on any distribution circuit with voltage regulating equipment, regardless of whether or not a centralized, dynamic voltage control system has been deployed.

Background

As part of their core responsibilities, utilities must supply electricity to customers within established power quality standards. The range of allowable voltages (i.e. 114 to 126 V), an aspect of power quality, is set by American National Standards Institute (ANSI) standards. In practice, utilities over-supply voltage to most customers due to line losses that reduce voltage as electricity flows along distribution circuits. This over-supply of voltage results in excess energy consumption by customers.

A load duration curve is a familiar concept that illustrates a key grid inefficiency related to grid capacity: underutilized capacity is built to meet peak demand that occurs in only a handful of hours per year. Although less well known, a similar inefficiency exists related to customer voltages: higher than necessary voltages are delivered to most customers since no single customer can receive voltage below the ANSI voltage floor. In both cases, the cost of supplying electricity is increased.



Comparing Voltage and Capacity Inefficiencies

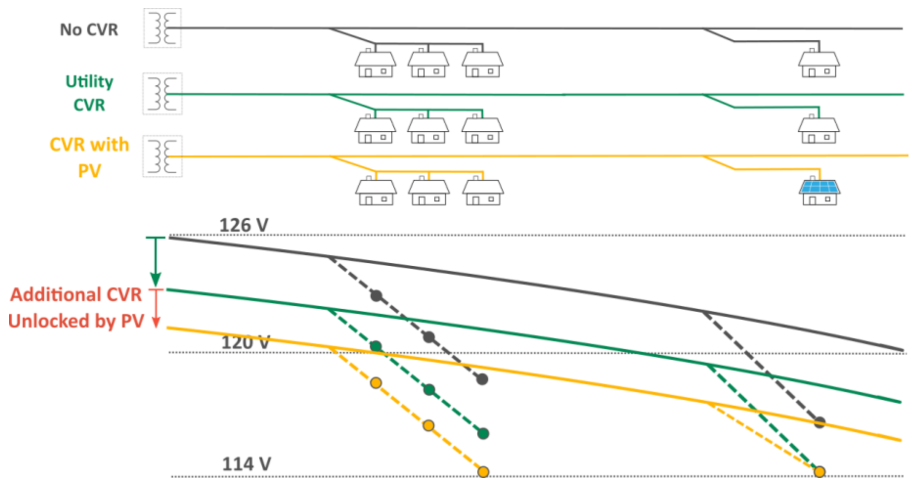
To address this voltage delivery inefficiency, utilities are increasingly deploying conservation voltage reduction (CVR) programs. CVR is a demand reduction and energy efficiency technique that flattens and reduces distribution voltage profiles in order to achieve a corresponding reduction in energy consumption and greenhouse gas emissions. A 1% reduction in distribution service voltage can drive a 0.4% to 1% reduction in energy consumption.[i] CVR programs typically save 0.5 to 4% of energy consumption on individual circuits,[ii] and are often implemented on a large portion of a utility's distribution grid.

Distributed PV and smart inverters can enable greater savings from utility CVR programs because those programs typically only control utility-owned distribution voltage regulating equipment. Such utility equipment affects all customers downstream of any specific device; therefore, CVR benefits in practice are limited by the lowest customer voltage in any utility voltage regulation zone (often a portion of a distribution circuit) since dropping the voltage any further would violate ANSI voltage standards for that customer. Because distributed PV with smart inverters can increase or decrease the voltage at any individual customer location, these resources can be used to more granularly control customer voltages.

How CVR + Distributed PV with Smart Inverters Creates Benefits

Typical distribution capacity planning studies do not consider the effects of the secondary distribution system, or secondary voltage drop – the portion of the distribution grid consisting of the power lines and pole top transformers that connect a customer's meter to the utility's primary distribution system.[ii] However, incorporating these details is critical to capturing the technical potential of CVR since secondary voltage drop is a limiting factor for utility voltage reduction strategies today.[iii] Within a voltage regulation zone, if the lowest customer voltages on the secondary distribution system were to be increased by one volt, the entire voltage regulation zone could then be subsequently lowered another volt. Therefore, the benefit of addressing the secondary voltage drop is significant.

The CVR concept is demonstrated in the figure below, where three voltage profiles are shown along a typical distribution circuit, from substation to end customers. The solid lines depict the primary voltage drop, while the dashed lines represent the secondary voltage drop. The reduction in voltage between the gray and green lines represents the voltage reduction that can be achieved solely by controlling utility-owned voltage regulating equipment within a traditional CVR scheme. However, potential voltage reduction is limited by the customer voltage at the end of the line, which in this example is already at the lowest permissible voltage according to ANSI standards. By installing distributed PV with smart inverters at this customer site, the secondary voltage drop is decreased and voltage is subsequently increased, which is evident in the reduced slope of the secondary voltage drop. This allows the overall voltage profile in yellow to be further reduced, increasing efficiency savings.



DERs control voltage locally and enable increased CVR benefits

While individual customer voltages vary within the allowable ANSI voltage band of 114 V to 126 V, suppose the average customer voltage is 120 V in the utility CVR example above (i.e. green line). In this case, a single customer receiving service at the voltage floor of 114 V prevents further savings through additional voltage reductions. To remove this inefficiency, deploying rooftop solar PV with a smart inverter at the limiting customer site can increase their voltage from 114 V to 115 V. Subsequently, the overall circuit voltage could also be lowered by a volt, delivering voltage to all customers at 119 V. Therefore, in this example, efficiency savings on the entire circuit are unlocked by installing a single rooftop PV system.

Benefits Calculation Methodology

The following methodology for determining the CVR benefits of distributed PV with smart inverters focuses on inverter contributions at the secondary (low voltage) level. This methodology quantifies the benefit from increasing the voltages of a subset of customers through targeted deployment of distributed PV with smart inverters in order to enable the subsequent decrease of voltages to all other customers on the circuit, resulting in energy efficiency savings. This methodology does not evaluate the incremental benefits to the primary (medium voltage) system due to the complexity introduced in modeling such benefits. Primary system benefits could be modeled if circuit model, equipment, and loading data were available.

A detailed methodology and accompanying calculator are provided to facilitate replication of the benefits described herein. The calculator can be applied to any distribution circuit, and can be found at www.solarcity.com/gridx.

Modeling Secondary Voltage Drop

Secondary voltage drop is a function of net load and the impedance of the service transformer and secondary line. To represent a typical secondary system, a simplified secondary model was utilized that consisted of typical pole top transformer, secondary conductor, and customer loads. For simplicity, all load is modeled as connected at a single location at the end of the secondary line. Consistent with the IEEE 8500-Node Test Feeder,[iv] the secondary system, and therefore the impedance, consists of a 25 kVA transformer and 50 feet of 4/0 Al secondary conductor. The single line diagram of this typical secondary system is depicted in the figure below.

Single Line Diagram of a Typical Secondary System (All Voltages Referenced to Ground)

Equation 1 below shows how the secondary voltage drop is calculated, which is the difference of voltage magnitude between the primary side of the service transformer and the customer's meter. The voltage at the primary side of the transformer can be derived using the transformer load and secondary impedance, as seen in Equation 2. The voltage at the meter is used as reference and is fixed to a nominal value, 120 ∠0° V, as shown in Equation 3. The difference in magnitudes between these two voltages equals the voltage drop across the secondary system (Equation 1).

$$VD = |V_{pri}\angle\theta_{pri}| - |V_{mtr}\angle\theta_{mtr}| \tag{1}$$

Where:

$$V_{pri}\angle\theta_{pri} = \overbrace{(I_{sec}\angle\theta_{sec})}^{Transformer\ Net\ Load} * \overbrace{(Z_{xf}\angle\theta_{xf} + Z_{line}\angle\theta_{line})}^{Secondary\ Impedance} + V_{mtr}\angle\theta_{mtr} \tag{2}$$

$$V_{mtr}\angle\theta_{mtr} = 120\angle 0°\ V \tag{3}$$

Modelling PV with Smart Inverter Capability

The voltage drop reduction of PV with smart inverters is a function of both the underlying PV generation as well as the reactive power capability of the smart inverter. Therefore, their combined impact on the secondary voltage drop must be modeled. To do so, PV production data from the National Renewable Energy Lab's (NREL) PVWatts® Calculator[v] is applied to an archetypal 5 kVA smart inverter. Inverter reactive power capability is activated for all hours of the day, but the smart inverter is assumed to maintain an active power priority because the economic value of active power is generally greater than reactive power (note: in geographies or times of day when reactive power is more valuable, this prioritization can be removed). Therefore, the amount of reactive power available per inverter is limited by the coincident apparent power generation. For example, at night when the PV is not generating, the smart inverter is capable of supplying the full 5 kVAr. However, during peak PV generation, the smart inverter is not capable of supplying any VArs. Since both active and reactive power enable a reduction in secondary voltage drop, any combination of active and reactive power output provides benefits.

A negative secondary voltage drop (i.e. voltage rise) can occur due to reverse power flows from PV back-feeding onto the primary, or excessive reactive power support during low loading conditions. While voltage rises can occur in practice, overall CVR benefits would be limited by the customer with the next lowest voltage. Therefore, secondary voltage drops are assumed to be able to be reduced to zero, but no incremental benefits are attributed to voltage rises on the secondary.

Relating Voltage Reduction to Energy Reduction

Equation 4 details of how the incremental CVR energy savings ($/kWh) are calculated for each voltage regulation zone.

$$\left(\frac{\$}{kWh}\right)_{Energy} = \frac{\sum_{t=1}^{8760}\left[\frac{VD_{noPV} - VD_{PV}}{V_{Base}} CVR_f\left(1 - \%_{Targeted}\right)E_{RegulationZone}C\right]}{E_{AnnualProducedByPV/Customer}\ \%_{Targeted}\ n_{TotalCustomers}} \tag{4}$$

The difference in the secondary voltage drop with and without PV (VD_{noPV} - VD_{PV}) is calculated for each hour over the course of one year (8760 hours) using Equations 1-3 above. The change in voltage drop after PV is deployed is then converted to a percentage by dividing by the nominal voltage at the customer meter (i.e. 120 V).

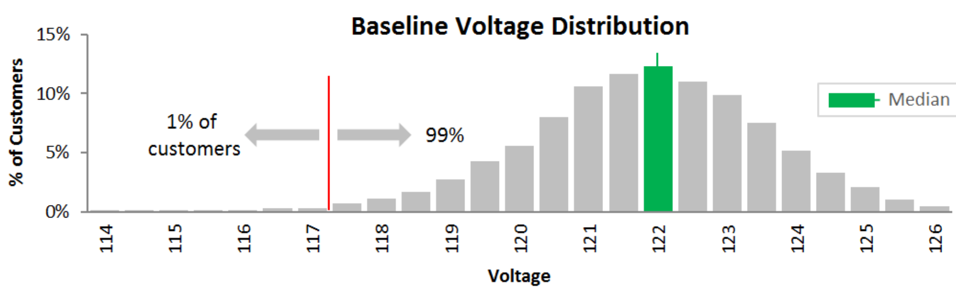
The percent reduction in energy for a voltage regulation zone is then determined by multiplying the percent reduction in voltage by the relevant *CVR factor*. The *CVR factor* of a load is the change in energy that results from a corresponding change in voltage. For example, if a load has a CVR factor of one, then a 1% reduction in voltage would result in a 1% reduction in energy. In this analysis, a CVR factor of 0.8 is used, which has been found to be representative of typical distribution circuits.[iii]

Percent reduction in energy for the entire circuit is then determined by multiplying the voltage drop and CVR factor by the percentage of customers that are having their voltage reduced. In this case, the customers who are experiencing the voltage reduction are those without PV installations ($1 - \%_{Targeted}$). Those customers with PV installations will receive the same voltage before and after the CVR scheme is in place, since the PV will raise their voltage while the CVR scheme will then lower it to its previous value. Equation 4 assumes that all customers have the same net load. In other words, 1% of customers consume 1% of the circuit load.

Targeting Customer PV Deployments

An Electric Power Research Institute (EPRI) analysis found that 90% of the secondary voltage drops were less than 2 V (on a 120 V base), but that 1% of voltage drops were greater than 4.2 V.[iii] This finding indicates that a small minority of customers experience outsized secondary voltage drops. Therefore, incremental CVR benefits could be unlocked if voltages at that small minority of customer sites could be raised, allowing for all customer voltages along the circuit to be subsequently lowered.

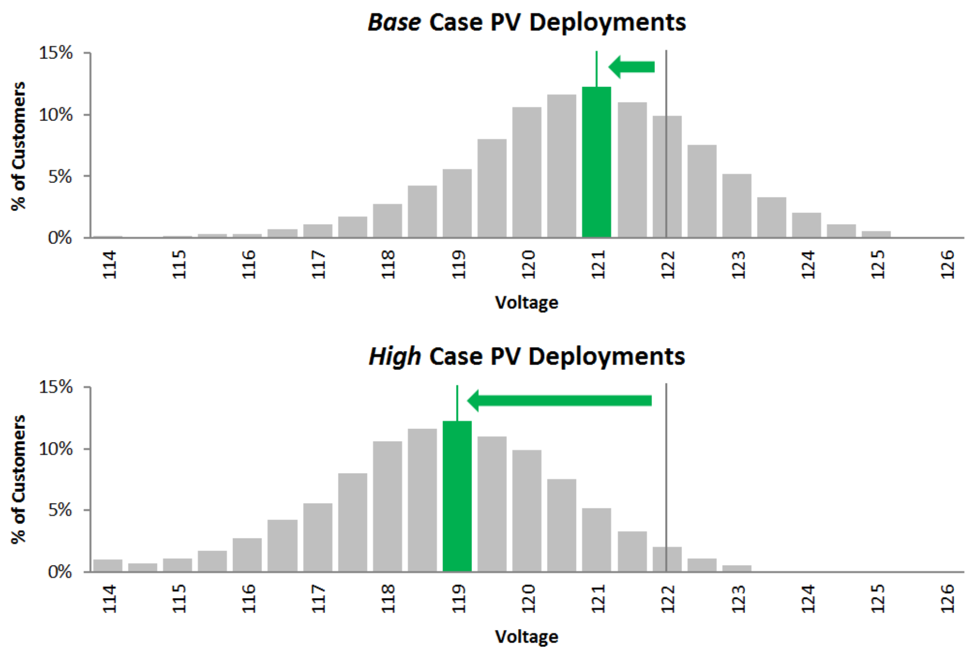
Voltage data from SolarCity customers offers a corroborating insight: that a small percentage of customers receive voltages at the low end of the ANSI voltage range. The *baseline* scenario in the figure below shows a histogram of voltages from 18,000 SolarCity customers at 5 PM on a particular day. PV production at 5 PM is low enough that these readings approximate voltages at customer sites without PV. In this data set, 1% of the customers receive power within the lowest 3 V of the ANSI range: from 114 V to 117 V. A similar distribution was found for voltages at 7 AM. If voltages at these 1% of customers could be raised, then significant energy efficiency benefits can be achieved by subsequently lowering all customer voltages on the circuit. Targeting PV deployments with smart inverters at these 1% of customers could achieve this goal.



Residential Voltage Distributions based on 18,000 SolarCity Customer Voltages

While this data suggests that increased CVR savings could be unlocked by siting PV at as few as 1% of customers, this analysis assumes that PV installations are deployed across 3% of total customers in order to account for the possibility that the lowest voltage customers may change throughout the day. This analysis also conservatively assumes that the lowest voltage customers are dispersed across the circuit on different secondary systems. In practice, if multiple low voltage customers were on the same secondary system, fewer PV systems would be required to achieve the same CVR benefit.

The figures below illustrate the impact that a targeted deployment of PV with smart inverters can have on customer voltages across a circuit. In the *base benefits* case, the lowest voltage customers are shifted up by 1 V, allowing the median service voltage to subsequently drop by 1 V from 122 V to 121 V for the remaining customers. In the *high* *benefits* case, the lowest voltage customers are shifted up by 3 V, allowing the median service voltage to subsequently drop to 119 V. This high benefits case is achievable if more than one low voltage customer occurs per transformer.



Voltage Shift in Base and Optimized PV Targeted Deployments

Quantifying Incremental CVR Benefits

After determining the percent reduction in energy, total financial savings in the numerator of Equation 4 are determined by multiplying the percent reduction in energy by the cost of energy in the voltage regulation zone. $/kWh benefits are calculated by dividing this number by the estimated annual energy production from all of the targeted systems. Equation 5 shows an annotated version of the energy benefits calculation highlighting where the change in voltage, reduction in energy, energy costs, and annual energy production are calculated.

$$\left(\frac{\$}{kWh}\right)_{Energy} = \frac{\sum_{t=1}^{8760}\left[\underbrace{\overbrace{\frac{VD_{noPV}-VD_{PV}}{V_{Base}}}^{\text{\% Change in Voltage}} * CVR_f\left(1-\%_{Targeted}\right)}_{\text{\% Reduction in Energy due to PV reducing voltage drop}} * \overbrace{E_{RegulationZone}C}^{\text{Utility CVR Energy Cost}}\right]}{\underbrace{E_{PV\_AnnualProducedByPVtion/Customer} * \%_{Targeted} * n_{TotalCustomers}}_{\text{Annual Energy Production of all Targeted PV Systems}}} \tag{5}$$

After determining the savings attributed to energy, the savings attributed to capacity can be similarly found by taking the demand reduction at peak and multiplying it by the distribution marginal cost of capacity (DMC) as seen in Equation 6.

$$\left(\frac{\$}{kWh}\right)_{Capacity} = \frac{\left[\frac{VD_{noPV}-VD_{PV}}{V_{Base}} CVR_f\left(1-\%_{Targeted}\right)P_{RegulationZone}DMC\right]_{At\ Peak\ Load}}{E_{AnnualProducedByPV/Customer}\ \%_{Targeted}\ n_{TotalCustomers}} \tag{6}$$

Total financial savings are determined by adding equations 5 and 6.

$$\left(\frac{\$}{kWh}\right)_{Total} = \left(\frac{\$}{kWh}\right)_{Energy} + \left(\frac{\$}{kWh}\right)_{Capacity} \tag{7}$$

Case Study

The previous section describes a methodological approach to quantify the benefits of integrating PV with smart inverters into utility CVR programs. In this section, the methodology is performed on a realistic case study of a 30 MVA substation in Southern California Edison's territory. In this case, a 30 MVA utility substation loading profile is synthesized from an aggregation of SolarCity residential loads for a year within Southern California Edison's (SCE) service territory. This proxy load profile is necessary because the utility data is generally not publicly available.

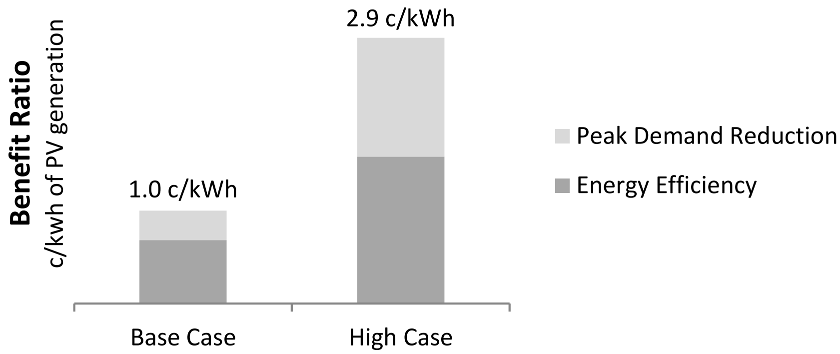
The results of these calculations can be articulated through a variety of perspectives and scopes, but this paper focuses on the relationship between incremental energy efficiency savings ($/year) unlocked by smart inverters and the corresponding PV production (kWh), yielding a $/kWh benefit. The table below summarizes the incremental energy and capacity savings that can be delivered by PV with smart inverters in the substation case study analyzed. Energy consumption and peak demand is reduced by approximately 0.4% per year, avoiding 350,412 kWh of incremental energy and 128 kW of capacity per year for the substation modeled.

System Benefits of PV with Smart Inverters in Utility CVR Schemes

	Energy Efficiency	Demand Reduction
Absolute Reduction	350,412 kWh/yr	128 kW/yr
% Difference	0.38%	0.41%
Avoided Cost Value	$39/MWh	$53/kW
Annual Value	**$14,613**	**$6,798**

The financial impact of these results can be measured by considering the value of the consumption and capacity reductions. Based on hourly energy costs from 2012-2015 in SCE territory,[vi] the value of these energy reductions avoids bulk system energy consumption at a weighted average cost of $39/MWh, yielding an annual energy benefit of $14,613. While the energy reductions also result in lower greenhouse gas emissions, the marginal cost of AB32 emission permits is assumed to be adequately captured in the avoided locational marginal prices (LMP). On the capacity side, assuming SCE's own marginal distribution capacity value of $53/kW-year,[vii] 128 kW in peak demand reduction generates benefits of $6,798 per year. In sum, the incremental energy efficiency and capacity benefits total $21,411 per year.

These benefits are enabled by the PV systems with smart inverters. A critical assumption identified in the methodology is the quantity of systems needed on the substation circuit to materially address the secondary voltage drop, which is a function of the feeder's underlying composition and voltage dispersion. In the *base* scenario, the 3% of customers with the lowest voltages are targeted with PV systems to reduce the secondary voltage drop by 1 V, yielding a 1.0 ¢/kWh benefit ratio. In the *high* benefits case, the same 3% of customers reduces the secondary voltage drop by 3 V, which yields a benefit ratio of 2.9 ¢/kWh. While SolarCity's voltage data suggests the *high* benefits case is realistic, the *base* case assumes a more conservative 1 V circuit voltage reduction. Specific results would vary by geography, circuit, and voltage regulation zone.



Efficiency Benefits of Smart Inverters in Utility CVR Programs

As stated previously, these *technical* benefits can be seen at penetrations as high as 10% of customers. However, if PV penetrations higher than 3% of customers are seen on a distribution circuit, this methodology will begin to underestimate the *economic* benefit per kWh, as the kWh produced in the denominator of the equation increase while the CVR benefits in the numerator remain relatively the same. Therefore, analysis at these higher penetration levels should incorporate benefits at the primary level, including voltage profile flattening and distribution line loss reduction. Further analysis at these penetration levels will require detailed circuit models and operational data for the utility's distribution system.

Realizing Voltage Benefits of Smart Inverters

Realizing smart inverter benefits in CVR programs is a relatively straightforward and low-cost opportunity to unlock energy efficiency savings, particularly in areas where smart meters are deployed that are capable of providing voltage data. Proactive voltage analysis by utility engineers and simple changes to the interconnection process could leverage the unique capabilities of smart inverters to address voltage inefficiencies deep in the distribution system.

Dynamic, centrally controlled CVR schemes are often thought to be a prerequisite to utilizing distributed PV to achieve CVR benefits. However, this is not the case. While dynamic CVR control systems can unlock additional efficiency savings, CVR benefits are achievable with open-looped control methods that use existing utility equipment, often only requiring easily administered device settings changes.[i,iii,viii] For example, the California Public Utilities Commission (CPUC) required their regulated utilities to implement CVR programs to avoid capacity shortages in 1976, a time when dynamic CVR control systems did not exist.[ix] Capturing CVR benefits therefore does not require significant investment by the utilities, and distributed PV with smart inverters can deliver CVR benefits on any circuit today, regardless of whether or not a dynamic, centrally controlled system has been implemented.

Conclusion

This method uses a simplified secondary model to estimate the reduction in voltage drop and proprietary voltage data to determine the percentage of customers to target to unlock additional CVR savings. The typical economic benefit is 1.0 ¢/kWh of PV production, which can increase the benefits of utility CVR programs by at least 10%, generating incremental savings of 0.4% to a typical 3% utility CVR energy savings rate.[ii] In a highly targeted scenario, these savings could be as high as 2.9 ¢/kWh of PV production. These enhanced benefits suggest that all ratepayers – solar and non-solar customers – would benefit if their utility proactively integrated PV with smart inverters into their CVR schemes.

A detailed methodology and accompanying calculator are provided to facilitate replication of the quantified benefits and to stimulate discussion. The calculator can be applied to any distribution circuit, and can be found at www.solarcity.com/gridx. Readers are encouraged to contact GridX@solarcity.com with any questions or comments.

Appendix 1 - Methodological Critiques

When performing analyses to make general statements and rules-of-thumb regarding the electric distribution system, a common critique is that every circuit is unique and all results depend on the characteristics of the circuit in question. While this critique is reasonable, the use of methodological simplifications and assumptions are routine in order to practically quantify and generalize results. A few of the key assumptions and simplifications are highlighted below, which potential critiques identified. Whenever possible, justification is provided for chosen methodologies and assumptions.

To quantify typical benefits on a sample distribution circuit, a simplified distribution secondary model was modelled based on the IEEE 8500-Note Test Feeder[iv] consisting of all load connected to a single tap off of a secondary transformer. In reality, the secondary system would be more complex, and a more exhaustive approach would be to model the actual secondary system in question. However, EPRI states that most utilities "do not model into the secondary system…and secondary conductor sizing and circuit connectivity are often not known or have errors."[iii] Therefore, this simplified approach is used. More accuracy in the underlying secondary model would likely increase the potential voltage drop and therefore increase benefits.

Another key assumption is the percentage of customers necessary to target in order to unlock increased CVR benefits. This benefits calculation methodology assumes 3% of customers must be targeted, based on current distributed PV penetration in California and by sampling SolarCity inverter voltage data. This sampling was done at sunrise and sunset, low solar production times of day in order to capture voltage not being influenced by the generation. Since evening peak typically occurs after the sun sets, these results suggest that the 3% could be even lower at evening peak. This assumption is similar to that used in EPRI's evaluation of the topic.[iii] Access to detailed customer voltage profiles would help refine these assumptions.

A key technical assumption is how significantly circuit voltage profiles could be lowered. Mechanically switched, voltage regulating equipment can typically only adjust voltage in 0.625% increments, implying that a secondary voltage drop would need to be corrected by 0.625% before any savings could be confidently achieved. However, consistent with Pacific Gas & Electric's (PG&E) Volt-VAr Optimization and CVR benefits calculation methodology,[x] a voltage improvement of less than 0.625% was assumed to be possible as it is unknown where in a voltage regulator band the output voltage resides. In reality, even a 0.1% change could push a voltage regulator out of its band and trigger a tap change operation. In this example, a 0.1% change in a secondary system would enable a 0.625% change on the primary system. However, a 0.1% change could also not be enough to trigger a voltage reduction, resulting in no benefits for this point in time. As in PG&E's methodology, it was assumed that these scenarios cancel out and the benefit of even a 0.1% change was calculated.

The calculations in this paper provide an estimate of value under the methodology and assumptions described. Access to utility distribution data would enable a more refined benefits calculation, and would also enable quantification of additional benefits to the primary distribution system.

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[i] "Review on Implementation and Assessment of Conservation Voltage Reduction", Wang and Wang, IEEE Transactions on Power Systems, May 2014.

[ii] “Evaluation of Conservation Voltage Reduction on a National Level”, Schneider, Fuller, Tuffner, and Singh, Pacific Northwest National Laboratory (PNNL) for the US Department of Energy (DOE), July 2010 http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19596.pdf

[iii] “Green Circuit Distribution Efficiency Case Study”, Electric Power Research Institute (EPRI), October 2010 http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001023518

[iv] "The IEEE 8500-Node Test Feeder”, Arritt and Dugan, Electric Power Research Institute (EPRI), 2010

[v] “NREL’s PVWatts® Calculator”, National Renewable Energy Lab (NREL), Accessed June 2016. http://pvwatts.nrel.gov

[vi] Prices were averaged based on hourly day-ahead LMP prices in the SCE DLAP for Jan 1, 2012 to December 31, 2015

[vii] See SCE fillings in California Public Utilities Commission Proceed on Net Energy Metering Successor Tariff. SCE’s assumption for Marginal Distribution Avoided Cost of Capacity was $53/kw-year, which is 55% lower than SCE’s marginal distribution cost of capacity ($118/kw-year) used in rate case filings. To be conservative, the authors use SCE’s assumption of $53/kw-year provided to the NEM 2.0 proceeding.

[viii] “Distribution Efficiency Initiative”, Northwest Energy Efficiency Alliance, December 2007.

[ix] “The Effects of Voltage Reduction on Distribution Circuit Loads”, Erickson and Gilligan, San Diego Gas & Electric (SDG&E), July 1982.

[x] “2017 General Rate Case Phase 1 Application 15-09-001 Data Response to PG&E Data Request No. ORA_185-Q20”, Dasso, Pacific Gas & Electric (PG&E), March 2016.